

Technical Issues in Transmission System Reliability

A Position Paper of the
Electric System Reliability Task Force
Secretary of Energy Advisory Board
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Section 1 -- Introduction

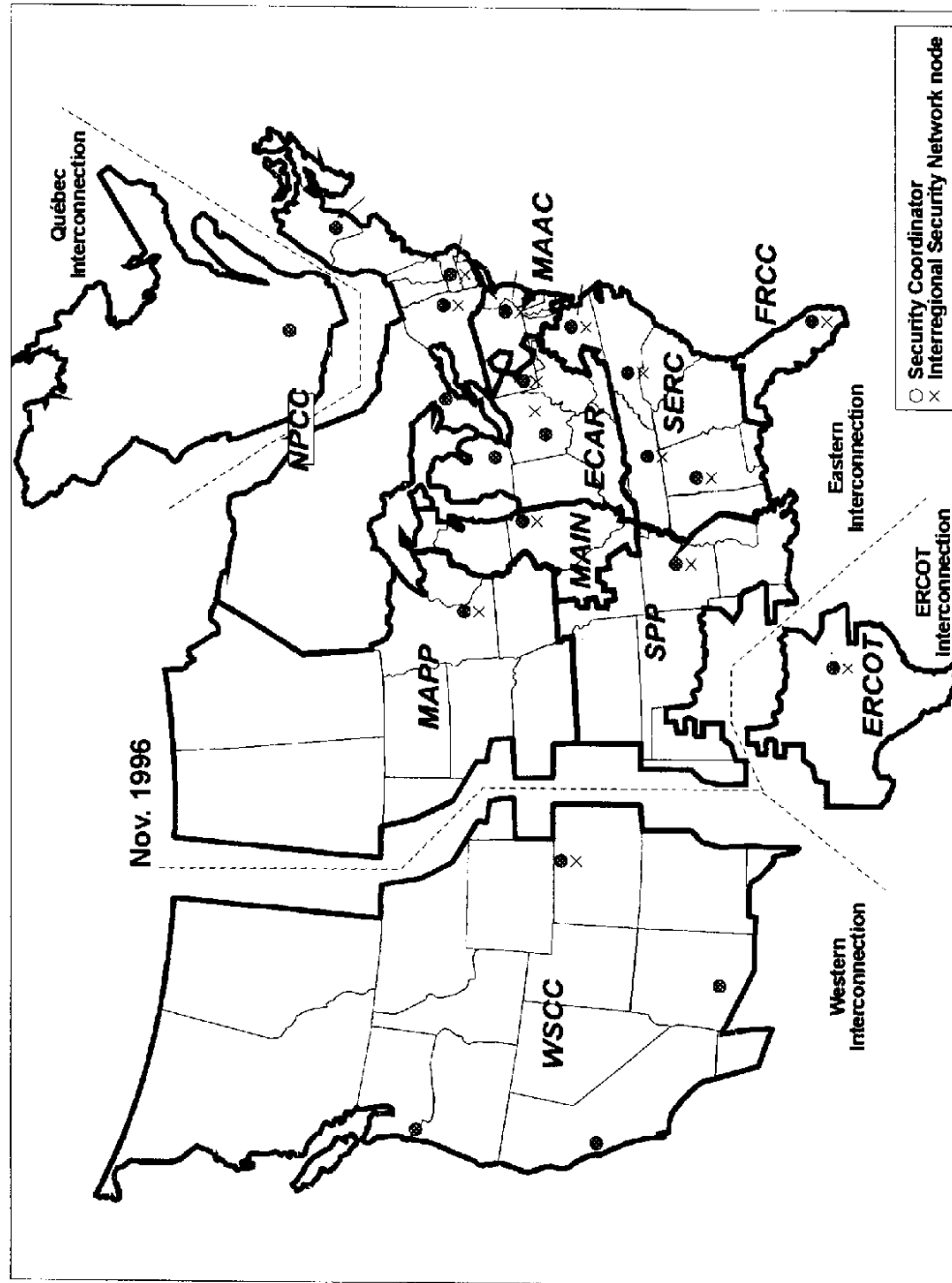
The vast, highly interconnected North American power system has been called the “greatest machine ever created.” Generators separated by thousands of miles must rotate together with split-cycle synchronism, and the flow of power over thousands of transmission lines must be coordinated over large regions of the country. Now, as profound changes sweep through the U.S. electric power industry, this complex machine is being required to work harder than ever before and perform in ways for which it was not originally designed. As a consequence, challenges face the industry on how to maintain power system reliability during this time of transition.

Structure of the Grid

The North American power grid comprises four major synchronous interconnections -- western, eastern, Texas, and Quebec -- which are further divided into ten Regional Reliability Councils (RRC). Each RRC has primary responsibility for maintaining grid reliability in its region, which involves coordinating the activities of numerous control centers belonging to individual utilities, power pools, or -- most recently -- independent system operators (ISOs). Together, the RRCs compose the North American Electric Reliability Council (NERC), which sets overall reliability policies and standards.

Within each synchronous interconnection, the transmission network acts as a superhighway for electricity commerce -- carrying large amounts of power over long distances to ensure that customers have access to the least expensive sources of electricity throughout the year. In the summer, for example, air conditioners in Los Angeles use power from hydroelectric facilities in the Pacific Northwest; in winter, power flows in the other direction. The network also protects customers from outages by enabling utilities to import power when one of their own generators must be taken off-line. Transfers of power from one synchronous interconnection to another are less common, since they require an interface to compensate for the fact that AC power is out of synchronization in the adjacent areas.

North American Interconnections & Regional Reliability Councils



The Challenge of Reliability

For a high-voltage power network to remain stable, synchronism must be maintained. When this synchronism is disturbed by inevitable local events -- such as a sudden loss of a major transmission line or a generator -- power can begin to flow in an uncontrolled manner, causing automatic safety devices to “trip” and isolate parts of the system to prevent damage to equipment. Maintaining transmission system reliability thus depends on the ability to prevent the spread of local disturbances.

When such control is lost, widespread outages can occur -- such as those that affected the western interconnection on July 2 and August 10, 1996. The initiating causes that led to these blackouts included line sags due to hot weather, flashovers from transmission lines to nearby trees, and misoperation of relays. Electrical disturbances created by these local events spread throughout the Western transmission network, eventually disrupting power to millions of customers in several states and adjacent areas of Canada and Mexico. It has been estimated that the financial losses suffered by California industry for the August 10 outage alone -- due to lost production, spoilage, etc. -- was in the range of \$1-3 billion.

The challenge of maintaining transmission reliability is thus to better understand and control disturbances that may originate in an isolated, local event but whose effects may almost instantaneously propagate throughout the system as a whole. The Northridge, California earthquake, for example, knocked generators off-line as far away as British Columbia. Fortunately, a variety of new technologies are becoming available that can help to assure transmission reliability while also enabling the grid to handle increased demand on transmission facilities that could result from industry restructuring.

Need for Reliability Management Technologies

Ultimately, complying with these regulatory mandates will require the use of new technologies on both transmission and distribution systems. As transmission networks handle more transactions and are operated at tighter margins, for example, electronic power controllers and more sophisticated methods of monitoring, communicating and analyzing system conditions will be needed. The transition to a competitive market will lead to unbundling of energy services such that acquisition of energy will be separate from voltage support, spinning reserves, standby generation, congestion management, and other ancillary services. This creates the opportunity to develop and demonstrate distributed technologies for the specific purpose of reliability management such as distributed generation, energy storage systems, voltage controllers, local network management system protection, and other technologies.

This report by the Electric System Reliability Task Force (Task Force) addresses some of the technical issues raised by restructuring and describes several of the advanced technologies that can be used to sustain system reliability while opening transmission networks to increased competition.

Section 2 -- Requirements for Communications, Databases, Control Systems Integration, and Information Management

Reliable operation of the bulk power system is currently supported by sophisticated computerized information management and control systems, which rely upon one or more databases and which utilize data communications systems. The systems currently in place have been procured by the transmission owners from a variety of vendors. With few exceptions, the systems in place today have proprietary communications protocols, database formats, and operational models, and were designed to support a relatively limited number and variety of transactions.

Now, the bulk power system is being asked to support an increasing number of ever-more diverse transactions. Additionally, wholly new reliability organizations -- such as the California ISO -- are being established in some parts of the country, with needs for new and complex information systems. Indeed, in California, where retail choice was expected to be launched on January 1, 1998, a short-term delay was needed to give adequate time to prepare ISO computer systems for full-scale operation. In order for the bulk power system to be operated reliably even in areas where such new systems are not being built from scratch, existing information and control systems must be upgraded to support the new transaction levels and unbundled services. In addition, as regional coordination is implemented, through ISO's or other organizational means, information sharing and communication between transmission system control centers become even more important.

The industry is aware of the issues presented here, and there are efforts under way by leading organizations (including NERC and the Electric Power Research Institute (EPRI)) to find solutions to these problems. The intent of this section is to highlight the principal technical concerns and to recommend how they should be addressed to assure reliable operation of the bulk power system in the future. These concerns are grouped according to their relevance to communications, databases, control systems, information management, and training.

Communications

The bulk power system is operated by personnel in control centers who must communicate effectively with their counterparts controlling other parts of the interconnected grid. Effective communication and information sharing is currently difficult and often does not occur adequately. The primary reason for this is the use of mutually incompatible communications systems. In the near term, new interfaces for inter-control center communications need to be developed and deployed. In the longer term, a non-proprietary communications protocol needs to be adopted industry-wide to insure communications compatibility of all control centers.

The Task Force recommends that an appropriate, non-proprietary standard for communications among control centers be adopted by the Self-Regulating Reliability Organization (SRRO) and endorsed by the Federal Energy Regulatory Commission (FERC).

Databases

New requirements for data models and database integration arise in an ISO where regional operators must coordinate operations across larger areas with many multi-party transactions taking place. Standards are needed which support information sharing between system operators, and which support the needs of all parties engaged in transactions.

Regional operators coordinating the efforts of multiple interconnected transmission systems will be less familiar with the details of some of the networks that make up their region. They must also coordinate the control of a much larger network than current system operators. The databases needed to support regional operations therefore must contain a great deal more knowledge of the system than previously required. In addition, data models for ISOs must support data from multiple sources to coordinate energy management functions across multiple, dissimilar energy management systems within a region.

The Task Force recommends that an appropriate, non-proprietary database access standard for control centers be adopted by the SRRO and endorsed by the FERC.

Information Management

Much of the information regarding the infrastructure of the bulk-power system currently in use is based on design specifications and as-built drawings. This information is largely dated and may not reflect the current status of the infrastructure with respect to available transfer capacity and safe operating margins. In addition, much of this information is only available from paper records or proprietary computer-aided design file formats. System operators must update and maintain transmission records appropriately to reflect current system capabilities and safe margins. These records must be made electronic and shared in accordance with FERC Orders 888 and 889.

As regional system operators are required to coordinate activities across larger segments of the interconnected grid, they will require information displays which cover larger geographic areas and integrate views of system models, load, status and available capacity data, weather data, risk assessments and safe operating margins. In addition, it is critical to have simulation capability to predict, prepare for and possibly mitigate congestion, and to understand the consequences of transactions and system state changes before they occur.

The Task Force recommends that the SRRO specify information management protocols that will ensure the complete interoperability of system operations records in compliance with FERC Orders 888 & 889.

In addition, the movement to competitive markets combined with trends toward increasing utilization of computer networks for information management and growing vulnerability to cyber threats indicates the need for substantial attention to information assurance. The recently completed report by the President's Commission on Critical Infrastructure Protection documents major threats and vulnerabilities to our critical infrastructures, including

the electric infrastructure, and highlighted cyber vulnerabilities as one of the principal areas requiring attention.

The Task Force recommends that the Department of Energy (DOE), in collaboration with the SRRO, EPRI, and other Federal agencies, examine information assurance issues for the interconnected electric system and establish appropriate cooperative programs to address these issues as warranted.

Training

As the industry moves to adopt these technical systems, it also needs to assure that the personnel who operate them are adequately trained in up-to-date systems, operating procedures and market protocols. Currently, there is a growing shortage of technically trained personnel who are essential to operating a reliable transmission system. In response to this need, the NERC has initiated a standard training program, which all control operators will have to pass by 2001.

The Task Force recommends that an appropriate training program for system operators be developed by the SRRO and endorsed by the FERC.

Section 3 -- Planning Tools for Increased Uncertainty

The 1996 breakups of the Western power system demonstrated the need for improved resources to deal with the unexpected. This is a problem that existed prior to wide-scale industry restructuring, and it is likely to continue as competition introduces a greater number of transactions, covering wider geographical areas and multiple control regions.

Treating Uncertainty in Reliability Assessment

Even if suitable planning models had been available, operating conditions preceding the August 10 breakup were far from normal and had not been examined in system reliability studies. These are generally performed weeks to months in advance, and planners cannot anticipate all combinations of seemingly minor outages that operation of a large power system may involve.

Short-term planning for uncertainty and the risks attending it can be mitigated in part if system capacity studies are performed with a much shorter forecasting horizon, based upon reasonable extrapolations of present operating conditions. This calls for much broader real-time access to those conditions than any one (regional) energy management system now provides. The mathematical problem for longer-term planning is even more formidable. The number of likely contingency patterns, already huge, is becoming more so in response to energy market changes. The Western Systems Coordinating Council and individual companies are already studying risk-based transmission planning. A discussion of specific technological developments required to address these issues is given below.

Technologies for Reliability Assessment

The requisite computer tools for treating uncertainty in reliability assessment over short time periods are currently being developed as part of the envisioned framework for Dynamic Security Assessment software. For longer term planning, future practices may represent model errors as contingencies. Even without this additional step, direct examination of each individual contingency pattern is not computationally feasible. Never a simple matter, contingency analysis must now reflect new linkages between system reliability and market economics, while observing mandates supportive of the public interest. Consequent decisions must be rendered in less time, in an environment of more uncertainty and risk.

Providing reliable and economical electricity in a more complex environment requires two parallel efforts toward better decisions. The first is to reduce uncertainty, in all its forms, through better and more timely information. The second is to use planning and decision tools that directly accommodate such uncertainty as still remains. The quantified descriptions of uncertainty that such tools require as inputs are products of the information process, and directly useful for many other purposes.

Developing analytical methods to deal with greater uncertainty is necessarily a broad, multi-faceted effort. New technologies to be addressed by this effort may include:

- • Mathematical tools that can examine power system signals for warnings of unstable behavior, in real time and very reliably;
- Mathematical criteria, tools, and procedures for reducing and/or characterizing errors in power system models;
- Characterizations and probabilistic models for uncertainties in power system operating conditions;
- Probabilistic models, tools, and methodologies for collective examination of contingencies that are now considered individually;
- Cost models for use in quantifying the overall impact of contingencies and ranking them accordingly (It is essential that these models be realistic, and suitable for use as standards for planning and operation of the overall electrical grid); and
- Risk management tools, based upon the above probabilistic models of contingencies and their costs, that "optimize" use of the electrical system while maintaining requisite levels of reliability.

Need for a Collaborative Approach

Development of the indicated technologies can be expedited through technology transfers from outside the power industry. Even so, there remain several difficult problems. The

knowledge base for actual power system dynamics, required both to define the subject technology and to obtain best value from its use, is not well evolved. Both should develop together, in or close to a practical field environment. That environment must also provide good observations of power system dynamics, leading edge planning tools, and knowledgeable staff.

The Task Force recommends that appropriate entities, such as the DOE, in cooperation with the electric power industry, develop risk-based analytical tools for reliability assessment and transmission investment planning.

Section 4 -- Application of Alternatives for VAR Support and Reliability Management

For any transmission system to function properly, its voltage must be supported by injection of reactive power, measured as volt-amperes reactive (VARs). Compared to the “real” power delivered from a generator to a load where it can perform useful work, reactive power maintains the constantly varying electric and magnetic fields associated with all AC circuits. For transmission networks, reactive power has primarily been provided as an ancillary service by central station generators. This need for VAR support is particularly acute in areas where power demand is met primarily through the importation of power from outside the local area.

It is possible to provide VARs through other means than generation, such as through the use of fixed mechanical capacitor or reactor banks and, more recently, through the use of power electronic controllers known collectively as Flexible AC Transmission (FACTS) devices. There are pros and cons to the use of such electronic controllers, however, ranging from cost effectiveness to effects on system reliability. The potential impacts of providing increased VAR support through the use of FACTS controllers therefore needs to be carefully assessed.

Additional alternatives include a variety of Distributed Resources (DR) -- which can provide both local, on-site generation and VAR support in the form of micro-turbines, fuel cells, demand reductions and photovoltaic devices. The use of DR can enhance system reliability by providing local generation for direct support of the distribution system. DR technologies may appear particularly attractive in situations where power system enhancements are required to avoid congestion costs and/or where generation close to load is being retired.

The Task Force recommends that the DOE undertake a comprehensive study of technological alternatives to central station VAR support, their potential impact on bulk-power system reliability, and impediments to the use of such alternatives. The Task Force recommends that the DOE consult with various industry participants, and report the results back to the FERC and the SRRO.

Section 5 -- Status of Reliability Research

The Task Force was briefed on reliability research programs of EPRI, vendors and the DOE.

Historically, there has been support for technology development through utility and industry collaborative research activities including funding from the DOE. There is consensus on the need for continued support for such technology development.

There are some significant issues concerning how such technology development should be supported. As the industry transitions to a more competitive model, there is both a reduction in funding from traditional sources and a need to develop alternative technologies for reliability management. Specifically,

- • DOE funding for reliability and transmission has declined substantially;
- Direct utility funding of research programs is being eliminated or significantly reduced;
- EPRI focus on transmission and distribution research has shifted from long-term to near-term payoff. In this environment, the traditional long-term focus that produced FACTS technologies would not be possible;
- Responsibility for reliability management is changing and there is a question about who is responsible for technology investments; and
- New tools and technologies are needed to address the need for reliability management in a more competitive market. For example, unbundling voltage support may require use of distributed technologies.

The Task Force recognizes that there are major technological areas relative to reliability R&D that need to be addressed. The Task Force is concerned that reliability-related R&D with long-term focus may be under funded by market forces alone. The DOE should monitor the funding gap from traditional sources and the need for alternative technologies to assure this need is addressed and a technology gap does not develop in reliability management technology.

The Task Force recommends that the DOE carefully monitor research on reliability technologies and make appropriate recommendations to the FERC and Congress to assure that gaps do not develop.

There are several technological areas with major potential impact on reliability. Eight of them are discussed below.

Electrical Energy Storage

Although some technologies for electrical energy storage have been used for a long time, their use has been limited. Relatively inexpensive, large-scale technologies -- such as pumped hydro -- can be used to provide extra energy to meet peak demand, but they cannot respond rapidly enough to counteract transient disturbances. Storage technologies with rapid response times -- such as batteries -- on the other hand, have been too expensive for widespread use in peak

shaving. Now, with electricity becoming more of a commodity, the need for a new storage technology that is both fast and inexpensive has become more urgent.

One promising technology now under development is superconducting magnetic energy storage (SMES). Recently, new concepts have been developed that greatly improve cost effectiveness of magnetic energy storage for both electrical system ride-through of disturbances and for transmission line stability enhancement. Cost-effective designs based on fully-developed, low-temperature superconducting cable now allow less than one cycle response for ride-through of transients or multi-seconds outages at large, power-quality sensitive industries. Recent analyses also show that rapid injection of real power from such magnets enhances the effectiveness of FACTS controllers in providing transmission stability.

New, high-temperature superconducting (HTS) materials may someday help lower the costs of SMES. Although HTS materials are themselves still costly, they are much less expensive to refrigerate, because they depend on cooling with liquid nitrogen, rather than liquid helium.

Superconducting storage technology is generally in the prototype demonstration phase. HTS materials are currently being tested in cables but are not yet ready for use in SMES because the HTS materials do not conduct well in high magnetic fields. Better HTS materials need to be developed that can withstand the high magnetic fields inherent in SMES devices. In addition, an industrial infrastructure must be established that is capable of producing the thousands of miles of HTS tape that would be used in SMES devices.

Distributed Resources as Power System Alternative

As mentioned earlier, DR include a variety of energy sources -- such as small combustion turbines, photovoltaics, fuel cells, and storage devices -- with capacities in roughly the 1-kW to 10-MW range. Deployment of DR on distribution networks could potentially increase the reliability and lower the cost of power delivery by placing energy sources nearer to demand centers. By providing a way to complement conventional power delivery systems, DR could offer supply flexibility, including greater use of environmentally benign renewable energy. DR can also be combined with power electronic controllers, which will provide the interface between small generation units and a utility distribution system.

Rapid introduction of DR could have profound effects on the operation and reliability of the power delivery system. An EPRI study indicates that DR could represent as much as 25% of new generation by 2010; a similar study by the Natural Gas Foundation concluded that this figure could be as high as 30%. One driving force will be the availability, within five years, of 25-100 kW microturbines for under \$300/kW. Another driver may be the recent development (with DOE funding) of an electric car based on fuel cells that use gasoline -- a technology that might eventually enable consumers to use their car's 50-kW fuel cell (or similar stationary fuel cells, perhaps running on natural gas) to power their homes during hours of peak demand.

Technologies to Expedite Customized Service

The basic design of many of today's distribution systems dates back to the 1950s and before, when electric reliability was not as critical as today. As deregulation provides customers with greater choice among retail electricity providers, competition will drive customization of service to meet the divergent needs of various market segments. In addition to their need for greater power reliability at the system level, customers are demanding lower rates and a greater variety of service options. In response, many utilities and power suppliers are experimenting with real-time pricing and seeking ways to integrate electricity with other services, including gas, cable, and telecommunications.

To accommodate these service alternatives, integrated communications and control will be needed to expedite data exchange and real-time operational command throughout a more decentralized and complex distribution system. The technical basis for such integration is currently being provided by the Utility Communications Architecture (UCA), which specifies open-systems protocols and standards for linking hardware and software from different vendors. The first utility demonstration of UCA's ability to provide the technical basis for integrating electric, telephone, water, and waste-water services is just getting underway.

Customer interface improvements will also be critical to offering new retail services. In particular, a low-cost electronic meter with two-way communications capability is needed to provide real-time pricing options. Even more sophisticated interface technologies will be required to facilitate integrated services that depend on high-bandwidth communications links. Customer interface research has reached the stage of conducting tests on pilot installations of a low-cost electronic meter. Development of a prototype hardware system for automatic meter reading using open networking standards is expected by 2000.

Electronic Controllers for Transmission Systems

Electromechanical controllers are too slow to govern the flow of alternating current in real-time, as needed to control loop flows and bottlenecks. FACTS is a family of high-voltage electronic controllers that can increase the power carrying capacity of individual transmission lines and improve overall system reliability by reacting almost instantaneously to disturbances. The advent of such "fast-VAR support" to replace the "slow-VAR support" provided by conventional control devices will also enable system operators to "dispatch" transmission capacity in much the same way that generator capacity is now dispatched.

FACTS technology has been under development for nearly twenty years and is now entering its third generation, with devices that can control all the parameters of power flow simultaneously without the need for large external circuit elements, such as a capacitor bank. Although FACTS technology has been demonstrated in various settings, the major challenge to full-scale commercialization is the need to reduce costs to achieve widespread use.

New semiconductor materials -- such as silicon carbide, gallium nitride, and thin-film diamond -- represent a technological "wild card" that could dramatically lower the cost of FACTS

devices by providing the basis for developing a power electronic equivalent of the integrated circuit. Also, the promise of going to a totally electronic device and thereby reducing costly transformers, would represent a significant cost breakthrough.

System Coordination Technologies for Power Grid

For transmission systems, the advent of new technologies could make it technically possible to integrate the North American power grids. In addition to this technological “push,” there is a regulatory “pull” designed to reduce wholesale electricity prices by facilitating competition in the bulk-power market. The result will be to make transmission lines the superhighways of electricity commerce -- carrying low-cost power over longer distances to meet the needs of customers who may now have electricity rates higher than those in neighboring regions.

If greater long-distance transfers of power are to be accomplished while maintaining power system reliability, improvements will be needed in network monitoring, on-line analysis, and system control.

A Wide-Area Measurement System (WAMS) provides the real-time information needed for a large, highly interconnected transmission network, based on satellite communications and time-stamping. By constantly monitoring conditions throughout a wide-area network, WAMS can detect abnormal system conditions as they arise, enabling the system to operate closer to its limits. WAMS technology is currently being incorporated into a major collaborative program to implement a synchronized monitoring system for the western North American power grid.

On-line system analysis will be needed in order for the information supplied by WAMS to be interpreted in real-time for use in directing FACTS devices to respond in a timely way to disturbances as they develop. On-line software tools will enhance the ability of dispatchers to schedule wholesale power transfers on a continental scale, hour-by-hour. Such tools will be critical for enhancing reliability, promoting open access, transferring low-price electricity over longer distances, and reducing operating costs significantly. Advanced software can also provide a probabilistic measure of Available Transfer Capability -- essentially a “reliability meter” dispatchers can watch in order to maximize power flow within the stability limits of their system.

Hierarchical control of a transmission grid involves coordinating intelligent local operation of power flow devices with system-level instructions from a dispatch center. Such control will have to become widespread in order to facilitate the vision of highly reliable, long distance power transfer. System operators need the ability to understand disturbances that may be developing in neighboring regions in order to properly ensure that they do not spread and that stability is maintained throughout the rest of the grid. Hierarchical control will be able to raise the power transfer limits of transmission systems over increasingly wider areas.

Electronic Controllers for Distribution Systems

Custom Power is the name used to describe a family of power electronic controllers designed for use on distribution systems to improve power quality levels, facilitate distribution automation, and expedite integration of distributed resources into the power system. Custom Power devices provide the key to reliability enhancement for customers. The cost of power electronics has declined to the point that this technology can be considered for use in controlling distribution systems, which require smaller, more numerous, less expensive installations than those involved in FACTS. Custom Power devices are now beginning to enter utility service and are expected to become commonplace over the next decade, as the price of electronics continues to fall. Custom Power devices can also be used in distribution automation applications to provide real-time network control and significantly reduce distribution system operating costs.

The major stumbling block to faster deployment of Custom Power devices is cost, and considerable R&D is still needed to re-engineer these controllers for greater efficiency. Again, the possible future use of new semiconductor materials offers a “wild card” chance of significantly lowering hardware costs. New designs for individual Custom Power devices may also be able to eliminate the need for incorporating costly transformers into these controllers.

Dynamic Integration of a Silicon-Intensive Load

Twenty years in the future, power systems will be faced with increasingly silicon-intensive loads. As a result, the mechanical inertia of the system will be less than with today’s motor-intensive loads. Because such inertia helps the system “ride through” momentary disruptions, the coming of predominantly silicon-based loads could contribute to dynamic instability.

More research needs to be focused on the unique reliability problems that could result from evolution of all-silicon loads. As a first step, computer models are needed that can identify the characteristics of such systems. In addition, the use of energy storage to replace the effects of mechanical inertia needs to be explored.

Development of an All-Underground Power Delivery System

Construction of new overhead transmission and distribution lines is becoming more difficult because of problems in siting and obtaining the necessary permits. By contrast, gas transmission companies have met much less resistance in siting new lines because they are underground. In addition, because underground facilities are generally less susceptible to disruptions caused by natural disasters, such as ice storms, their increased use could improve transmission reliability. The cost of putting electric power lines underground, however, can range up to a factor of ten higher than for overhead installations of equivalent capacity.

Recent experience indicates that this cost differential could be reduced through research. In many cases, for example, directional drilling can be used instead of traditional trenching methods to install conduits for new underground lines. Such guided boring technology can not

only lower construction costs in many instances but also substantially reduce environmental impact of installation. Further research can be expected to bring the life-cycle costs of undergrounding much closer to the equivalent costs of overhead alternatives.

Section 6 -- Conclusion

Given the current restructuring of the U.S. electric industry, maintaining the reliability of the transmission systems will require careful integration of existing systems and advanced technologies. Deployment of advanced technologies needs to be coordinated in accordance with regional and national standards and procedures. Such standards and procedures should be adopted.

The Task Force has made several specific recommendations summarized below, which support the timely and effective use of reliability-related technologies. We believe the adoption of these recommendations will increase the probability of maintaining reliable transmission system operation, resulting in lower costs and improved service to electricity customers throughout the country.

Recommendations Summary

The Task Force recommends that:

- 1) An appropriate, non-proprietary standard for communications among control centers be adopted by the SRRO and endorsed by the FERC;
- 2) An appropriate, non-proprietary database access standard for control centers be adopted by the SRRO and endorsed by the FERC;
- 3) The SRRO specify information management protocols that will ensure the complete interoperability of system operations records in compliance with FERC Orders 888 & 889;
- 4) The DOE, in collaboration with the SRRO, EPRI, and other Federal agencies, examine information assurance issues for the interconnected electric system and establish appropriate cooperative programs to address these issues as warranted;
- 5) An appropriate training program for system operators be developed by the SRRO and endorsed by the FERC;
- 6) Appropriate entities, such as the DOE, in cooperation with the electric power industry, develop risk-based analytical tools for reliability assessment and transmission investment planning;

- 7) The DOE undertake a comprehensive study of technological alternatives to central station VAR support, their potential impact on bulk-power system reliability, and impediments to the use of such alternatives. The Task Force recommends that the DOE consult with various industry participants, and report the results back to the FERC and the SRRO; and
- 8) The DOE carefully monitor research on reliability technologies and make appropriate recommendations to the FERC and Congress to assure that gaps do not develop.